ILLINOIS POWER COMPANY

ILLINOIS COMMERCE COMMISSION

DOCKET NO. 01- ____

EXHIBITS SPONSORED BY KAREN R. ALTHOFF

JUNE 1, 2001

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ILLINOIS COMMERCE COMMISSION

DOCKET NO. 01-

PREPARED DIRECT TESTIMONY OF KAREN R. ALTHOFF

JUNE 1, 2001

I. Introduction and Witness Qualifications

1. Q. Please state your name, business address and present position.

A. Karen R. Althoff, 500 South 27th Street, Decatur, Illinois, 62521. I am a Senior Regulatory Specialist in the Business Development Services department at Illinois Power Company ("Illinois Power", "IP" or the "Company").

2. Q. Please summarize your educational background and professional experience

A. I am a 1983 graduate of Millikin University, Decatur, Illinois, with a Bachelor of Science Degree in Accounting. I began my employment in 1983 with the Company as an Internal Auditor. Since that time, I have held positions at the Company as Accountant, Senior Financial Analyst, Staff Accountant, Supervisor – Financial Reporting, Business Leader and Senior Regulatory Specialist. I am a Certified Public Accountant and a member of the American Institute of Certified Public Accountants and the Illinois Certified Public Accountants Society.

3. Q. What are your responsibilities in your present position?

A. My primary responsibilities include development of cost of service and rate design studies. In addition, I have responsibilities for customer rate analyses and various costing activities.

4. Q. Have you previously testified before the Commission?

A. Yes. I testified in Docket Nos. 99-0120 & 99-0134 (Consolidated), Illinois Power's 1999 Delivery Services Tariff ("DST") case.

II. Purpose and Scope

5. Q. What is the purpose of your testimony?

A. I am presenting the results of Illinois Power's embedded cost of service study ("ECOSS") for the electric distribution business. The study was prepared under my supervision and direction. In addition, I am presenting costing support for the Company's single bill option credit, the retail marketing and uncollectible costs in Rider TC and for certain fees associated with delivery services. Finally, I am presenting the revenue requirement and ECOSS for the metering function subject to unbundling.

6. Q. In addition to your testimony in IP Exhibit 8.1, which consists of questions and answers 1 through 28 inclusive, are you sponsoring any other exhibits?

A. Yes, I am sponsoring IP Exhibits 8.2 through 8.9 that were prepared by me or under my supervision and direction.

III. Electric Distribution Embedded Cost of Service Study

7. Q. For what test year was the distribution ECOSS performed?

A. The distribution ECOSS was prepared based on the historical test year ended December 31, 2000, adjusted to reflect known and measurable changes through June 30, 2002.

8. Q. What costs and investments were used to prepare the distribution ECOSS?

A. The costs and investments used to prepare the distribution ECOSS were those that comprise the Company's distribution services revenue requirement, as presented by IP witness Mortland.

I did not make any separate determinations regarding the appropriateness of including any particular expense or capital item in the ECOSS.

9. Q. What is shown on IP Exhibit 8.2?

A. IP Exhibit 8.2 summarizes the results of the ECOSS. Page 1 of IP Exhibit 8.2 shows the electric distribution rate base and expenses for the customer classes: residential, non-residential small use, non-residential demand metered and lighting. The non-residential small use customer class consists of non-residential customers using less than 61 kWh per day in a summer billing month and unmetered services. The non-residential demand metered customer class consists of all remaining non-residential customers, other than lighting customers. Page 2 of IP Exhibit 8.2 reflects the allocation of distribution costs by the customer classes and then the classification of these costs as demand-transmission, demand-subtransmission, demand-distribution and customer-related.

10. Q. Please explain the general methodology used in developing the distribution ECOSS.

A. The starting point was the delivery services revenue requirement. Each rate base and expense item was classified on the basis of cost causation to demand-subtransmission, demand-distribution or customer. Demand-subtransmission and demand-distribution costs are those investments and expense items that are incurred to meet system peak load requirements and local maximum demands, respectively. In the development of distribution plant in IP's ECOSS model, the capital asset costs are segregated according to voltage level. This segregation is based on a detailed review of property records. Customer-related costs are those investments and expense items which are incurred to serve customers and which do not vary with changes in consumption, such as the cost of the customer's meter and service drop, as well as a portion of the distribution system.

11. Q. How were subtransmission and distribution demand-related costs allocated to the customer classes?

A. Subtransmission demand-related costs were allocated to customer classes based on the contribution of each customer class to the system's coincident peak demand. Distribution demand-related costs were allocated to the customer classes based on the non-coincident peak ("NCP") demand of each customer class below the subtransmission level. Use of the class maximum NCP demands for allocation of distribution demand-related costs reflects the diversity of each class' load and the fact that facilities installed at this level are sized to serve localized load centers that may or may not peak coincident with the system.

12. Q. How were customer-related costs allocated?

A. Several different allocation factors were used to allocate customer-related costs. For example, one allocation factor was developed on the basis of the number of customers served within each customer class. Weightings were applied to the number of customers in each class to recognize cost differences among customer classes. As another example, uncollectible accounts expense was allocated based on the percentage of residential and non-residential uncollectible accounts expense, and then allocated to the rate classes based on number of customers. The same weightings were applied to the number of customers to allocate meter reading and customer billing expenses. Meters and services were allocated to rate classes based on current replacement cost of the types of assets required to serve the individual rate classes.

IV. Transaction Fees for Delivery Services

13. Q. Do the Company's delivery services tariffs include certain transaction fees for various activities associated with the provision of delivery services?

A. Yes. Included in the Company's tariffs are certain transaction fees related to the provision of delivery services. The inclusion of these fees was previously approved in Illinois Power's initial DST case.

14. Q. Are you presenting cost support for changes to any of these fees in your testimony?

A. Yes, I am. Given that the Company has been offering delivery services since October 1999, business processes associated with these fees were reviewed to determine whether any of the currently approved fees should be revised. IP witness Holtzscher describes the review of various processes. I am providing costing information for the reviewed processes that reflect changes from the last DST case, and for those processes which are new.

15. Q. What is shown on IP Exhibit 8.3?

A. IP Exhibit 8.3 provides the cost support for the Purchase Power Option ("PPO") calculator fee. The PPO calculator is a new service that the Company is offering. Cost support for two separate charges is presented on this Exhibit. The first set of cost support reflects the maintenance cost for our web-site that provides PPO estimates. The process involves two hours monthly for an account manager to update data supporting the PPO calculator plus two hours monthly for a computer analyst to maintain the site. The second set of cost support reflects the maintenance cost for manually-processed PPO estimates. This process involves two hours monthly for an account manager to update the PPO calculator plus a quarter of an hour per inquiry for the account manager to obtain authorization verification and respond to the user's inquiries. The per-user costs were determined based on the numbers of customers who have reviewed PPO as an option. This level is expected to continue. The resultant costs are $3.46 per customer, RES or agent inquiry to the web-based PPO calculator, and $11.62 per inquiry for inquires not made via web access (e.g., telephone inquiries). These costs support the charges of $3.50 and $11.50 per inquiry, respectively, that are included in the Company's proposed tariffs sponsored by Ms. Voiles.

16. Q. What is shown on IP Exhibit 8.4?

A. IP Exhibit 8.4 provides the cost support for a monthly fee to Retail Electric Suppliers ("RES") and agents for unlimited access to the web-based PPO calculator and to customer consumption history information on IP's web-site. This fee is in lieu of "per use" fees.

17. Q. What is shown on IP Exhibit 8.5?

A. IP Exhibit 8.5 provides the cost support for off-cycle switching fees. There are four separate costs developed on this exhibit to distinguish the differences in the processes for handling non-EDI and EDI transactions and for customers switching who have interval metering versus non-interval metering. The costs detailed on this Exhibit do not include the charge for Direct Access Service Requests ("DASR") as they are incremental; however, the DASR charges are reflected in a separate column to show the total switching fees for each type of customer. The costs for customer contact/questions associated with EDI-type transactions reflect reduced time expended by the Company personnel as compared to non-EDI transactions. Customers with interval metering require an additional step to split and upload metering data into our billing system along with additional time expended to verify billing information.

18. Q. What is shown IP Exhibit 8.6?

A. IP Exhibit 8.6 provides the cost support for the administrative activities performed for customers served under Rider PRS. The processes for administering this service are described by IP witness Holtzscher. Cost support for this administrative charge is presented on Exhibit 8.6. Based on this cost information, the proposed administrative charge for non-interval customers under Rider PRS is $80.00, while the monthly administrative charge for interval customers is $100.00.

V. Single Bill Option

19. Q. Have you provided an updated single bill option credit?

A. Yes, I have updated the single bill option credit to reflect actual historical information for the year ended December 31, 2000. In addition, I am updating the single bill option credit for the postal rate increase that went into effect in January 2001. This information is provided in IP Exhibit 8.7.

20. Q. Was development of the revised single bill option credit based on the criteria specified in the order in the Company's 1999 DST case?

A. Yes, it was.

21. Q. Have you developed separate single bill option credits for residential and non-residential customers?

A. Yes, I have. After reviewing the steps and costs in the single bill option credit process, it was determined that all steps and costs are applicable to both residential and non-residential customers. The only costs that are appropriate to segregate by residential and non-residential categories were the expenses associated with uncollectibles.

22. Q. What are the resultant single bill option credits?

A. As shown on IP Exhibit 8.7, the resultant single bill option credit is $0.439 per residential customer per month and $1.133 per non-residential customer per month if the RES assumes responsibility for payment. If the RES does not guarantee payment then the single bill option credit is $0.213 per month for both residential and non-residential customers. However, if a customer takes both gas service and electric delivery service from the Company then the SBO credit the customer would receive relates solely to the expenses associated with uncollectibles (assuming the RES assumes responsibility for payment of the delivery services bill), since IP must continue to send a bill to the customer and will continue to incur the billing costs. The credits in this situation would be $0.226 per customer per month for residential customers and $0.920 per customer per month for non-residential customers.

VI. Unbundled Meter Costs

23. Q. Have you provided updated costs relating to meters subject to unbundling?

A. Yes, I have updated the costs for meters subject to unbundling. The metering charges currently in Service Classification 110 are based on 1997 costs. The starting point for this cost development is based on the revenue requirement in the instant case. The portion of rate base and operating expenses attributable to providing metering service was then determined.

24. Q. Please summarize the meter service revenue requirement you have developed.

A. As shown on IP Exhibit 8.8, the meter service revenue requirement is $27,481,000 based on a rate base of $41,240,000 and operating expenses and income taxes of $23,680,000.

25. Q. Was development of the meter service revenue requirement subject to unbundling based on the criteria utilized in developing the metering charges approved in Docket No. 99-0013?

A. Yes, it was.

26. Q. Please describe IP Exhibit 8.9.

A. IP Exhibit 8.9 is a summary of the results of an ECOSS used to determine the meter service revenue requirements by customer rate class. The allocation to the customer rate classes was done on a consistent basis with the electric distribution revenue requirement allocation in the instant case. However, as shown on IP Exhibit 8.9, no portion of the metering revenue requirement was allocated to the lighting class since lighting service is unmetered.

VII. Rider TC - Retail Marketing and Uncollectible Costs

27. Q. Have you provided updated costs relating to retail marketing and uncollectible costs for use in adjusting market values in Rider TC and Rider PPO?

A. Yes, I have updated these costs. The Retail Marketing Costs is 0.0024 cents per kWh. This cost is comprised of the 2000 Sales Expenses as found in IP's FERC Form 1 ($459,000) divided by the 2000 Sales to Ultimate Consumer (18,950,067,000) as found in IP's FERC Form 1. The Retail Marketing and Uncollectible Costs is 0.0248 cents per kWh. This cost is comprised of the Retail Marketing costs stated above plus the 2000 Uncollectible Expense allocated to production ($4,249,000) divided by the 2000 Sales to Ultimate Consumer.

28. Q. Does this conclude your prepared direct testimony?

A. Yes, it does.

Illinois Power Company
Distribution Embedded Cost of Service Study
For the 12 Months Ended December 31, 2000
(Thousands of Dollars)

Line No.		Total Residential Rate Class 1	Total Non-Residential Small Use Rate Class 2	Total Non-Residential Demand Rate Class 3	Total Lighting Rate Class 4	Total ICC Delivery Services Jurisdiction
	Allocation of Rate Base					
1	Electric Plant in Service	$ 1,017,123	$ 46,065	$ 536,398	$ 149,643	$ 1,749,229
2	Less: Reserve for Depreciation	379,794	17,707	200,805	66,918	665,224
3	Net Plant in Service	637,329	28,358	335,593	82,725	1,084,005
4	Rate Base Additions	15,774	732	7,459	2,360	26,325
5	Rate Base Deductions	(104,694)	(4,489)	(55,791)	(16,433)	(181,407)
6	Total Rate Base	$ 548,409	$ 24,601	$ 287,261	$ 68,652	$ 928,923
	Allocation of Expenses					
7	Operation and Maintenance	$ 73,881	$ 4,436	$ 32,578	$ 6,638	$ 117,533
8	Depreciation & Amortization Expense	27,186	1,294	13,952	3,815	46,247
9	Taxes Other Than Income Taxes	19,381	867	10,282	2,892	33,422
10	Income Taxes	12,094	682	5,564	1,145	19,485
11	Deferred Income Taxes	5,704	241	3,105	903	9,953
12	Deferred Investment Tax Credit - Net	(330)	(13)	(179)	(51)	(573)
13	Total Operating Expenses	$ 137,916	$ 7,507	$ 65,302	$ 15,342	$ 226,067

Illinois Power Company
Distribution Embedded Cost of Service Study
For the 12 Months Ended December 31, 2000
(Thousands of Dollars)

Line No.		Total Residential Rate Class 1	Total Non-Residential Small Use Rate Class 2	Total Non-Residential Demand Rate Class 3	Total Lighting Rate Class 4	Total ICC Delivery Services Jurisdiction
	Revenue Required					
1	Demand Transmission	$ 2,521	$ 91	$ 2,353	$ 79	$ 5,044
2	Demand Substransmission	18,781	677	17,530	593	37,581
3	Demand Distribution	114,369	4,077	57,722	3,377	179,545
4	Customer Components	52,858	4,847	14,544	17,297	89,546
5	Gross Revenue Requirement	188,529	9,692	92,149	21,346	311,716
6	Other Revenues	(2,593)	(364)	(6,403)	(14)	(9,374)
7	Net Revenue Requirement	$ 185,936	$ 9,328	$ 85,746	$ 21,332	$ 302,342

Illinois Power Company

Cost Support:
PPO Calculator Fees

Line No.	Activity	Labor	Hourly Loaded Wage Rate	Total Activity Cost	Rounded
	I. Cost Per Inquiry for Web-Based Application				
	PPO Calculator Maintenance - Web-Based				
1	Maintenance performed by RBC, per year	24 Hr	$ 38.98	$ 935.51	
2	Information Technology maintenance, per year	24 Hr	$ 33.09	$ 794.21	
3	Total annual wages			$ 1,729.72	
4	Estimated number of PPO calculations per year			500	
5		**Total Per User "Hit"**		**$ 3.46**	**$ 3.50**
	II. Cost per Inquiry for Manually-Processing (Non-Web Based) Requests				
	PPO Calculator Maintenance - Manual				
6	Maintenance performed by RBC, per year	24 Hr	$ 38.98	$ 935.51	
7	Estimated number of PPO calculations per year			500	
		Subtotal		$ 1.87	
8	Authorization verification and discussion by RBC, per inquiry	0.25 Hr	$ 38.98	$ 9.74	
		Total Per User "Hit"		**$ 11.62**	**$ 11.50**

Illinois Power Company

Cost Support:
Monthly Fee for Access to PPO Calculator and Consumption History Information

Line No.	Activity				Total Cost
	I. Development of Monthly PPO Calculator (Web-Based) Charge				
1	Estimated number of PPO calculations per year			500	
2	Estimated number of Retail Electric Supplier (RES)			7	
3	Line 1 divided by line 2			71	
4	Estimated number of PPO calculations per month by RES (Line 3 divided by 12 months)			6	
5	Charge for PPO calculator maintenance	$ 3.50	(1)		
6	Charge for consumption history	$ 1.00	(2)	$ 4.50	
7	Line 4 multiplied by line 6				$ 27.00
	II. Development of Monthly Consumption History Charge				
8	Assume one consumption request per workday per RES - monthly			20	
9	Charge for consumption history			$ 1.00	
10	Line 8 multiplied by line 9				$ 20.00
11	Total Monthly Charge (lines 7 and 10)				$ 47.00

(1) Based on costs for web-based PPO calculator in IP Exhibit 8.3.
(2) Per charges in Standard Terms and Conditions Section 4(g)

Illinois Power Company

Cost Support:
Off Cycle Switching

Line No.	Activity	Labor	Hourly Loaded Wage Rate	Total Activity Cost*	Rounded	DASR Fee (1)	Total Switching Cost
	Non-EDI - Non-Interval Metering						
1	Customer contact/questions - RBC	15 Min	$ 38.98	$9.74			
2	Account maintenance - Customer Service Representative	10 Min	$ 18.82	$3.14			
3	Verification of billing - Accounting Clerk	10 Min	$ 24.66	$4.11			
4				**$16.99**	**$17.00**	**$18.00**	**$35.00**
	Non-EDI - Interval Metering						
5	Customer contact/questions - RBC	15 Min	$ 38.98	$9.74			
6	Account maintenance - Customer Service Representative	10 Min	$ 18.82	$3.14			
7	Upload MV90 file - Accounting Clerk	20 Min	$ 24.66	$8.22			
8	Verification of billing - Large Power Clerk	30 Min	$ 31.74	$15.87			
9				**$36.97**	**$37.00**	**$18.00**	**$55.00**
	EDI - Non-Interval Metering						
10	Customer contact/questions - RBC	5 Min	$ 38.98	$3.25			
11	Account maintenance - Customer Service Representative	10 Min	$ 18.82	$3.14			
12	Verification of billing - Accounting Clerk	10 Min	$ 24.66	$4.11			
13				**$10.50**	**$10.00**	**$6.00**	**$16.00**
	EDI - Interval Metering						
14	Customer contact/questions - RBC	5 Min	$ 38.98	$3.25			
15	Account maintenance - Customer Service Representative	10 Min	$ 18.82	$3.14			
16	Upload MV90 file - Accounting Clerk	20 Min	$ 24.66	$8.22			
17	Verification of billing - Large Power Clerk	30 Min	$ 31.74	$15.87			
18				**$30.48**	**$30.00**	**$6.00**	**$36.00**

(1) Per Service Classification 150, Section 5
* Exclusive of DASR time requirements and subsequent costs.

Illinois Power Company

Cost Support:
Partial Requirements Service Administration Fees

Line No.	Activity	Activity Performed By	Annual Labor		Total Activity Cost
	Customer initialization:				
1	- customer contact/discussion/analysis	RBC	8.0 Hr	$	311.84
2	- coordination of customer account	RBC/Billing Services	8.0 Hr	$	299.70
	Customer Sign-up:				
3	- contract preparation	RBC	4.0 Hr	$	155.92
4	- legal review of contract	Legal	1.0 Hr	$	73.28
	Clerical support:				
5	- contract processing	Accounting Clerk	1.5 Hr	$	36.99
6	- computer entry	CSR	0.25 Hr	$	4.71
7	- pending work request processing	CSR	0.25 Hr	$	4.71
8	- billing advices	CSR	1.5 Hr	$	28.23
9	- cost of contract / renewal mailings			$	9.23
10	**Total Annual Cost**			$	924.60
11	**Monthly Cost**			**$**	**77.05**
	Non-Interval Metering				
12	- verification of billing	Accounting Clerk	2.0 Hr	$	49.31
13	**Total Annual Cost**			$	49.31
14	**Monthly Cost**			**$**	**4.11**
	Interval Metering				
15	- upload MV90 file	Accounting Clerk	2.0 Hr	$	49.31
16	- verification of billing	Large Power Clerk	6.0 Hr	$	190.45
17	**Total Annual Cost**			$	239.77
18	**Monthly Cost**			**$**	**19.98**
19	**Partial Requirements Service Administration Fee - Non-Interval Metered Customer (lines 11 + 14)**			**$**	**81.16**
20	**Partial Requirements Service Administration Fee - Interval Metered Customer (lines 11 + 18)**			**$**	**97.03**

Illinois Power Company

Single Bill Option Credit (1)

Line No.	Item	FERC Account	Annual Cost	Per Bill Cost	Applicable to Residential Per Bill Cost	Applicable to Non-Residential Per Bill Cost
	Costs associated with billing function					
	O&M					
	Labor:					
1	2 - Jr. Clerks ($14.82/hr plus loadings)	903	$ 82,606	0.0106		
2	Supervisory Allocation	901	$ 5,181	0.0007		
	Other:					
3	Contractor - Payment Processing	903	$ 1,559,220	0.1999		
4	Building O&M	935	$ 21,432	0.0027		
5	Maintenance of Printers	935	$ 53,588	0.0069		
6	Maintenance of Inserter	935	$ 54,000	0.0069		
	Materials and Supplies					
7	Printer Supplies (toner, etc.)	903	$ 20,003	0.0026		
8	Bill Forms	903	$ 155,160	0.0199		
9	Outgoing Envelopes	903	$ 102,900	0.0132		
	Return Envelopes:					
10	Regular	903	$ 49,712	0.0127		
11	Special	903	$ 50,500	0.0129		
12	Postage	903	$ 2,082,600	0.2670		
13	**Subtotal**			**0.5560**	**0.5560**	**0.5560**
	Expenses associated with Uncollectibles					
14	Uncollectible Expense Processing (DS Allocation)	903	$ 1,090,931	0.1399	0.1040	0.4232
15	Uncollectible Expense (Delivery Service Allocation)	904	$ 1,281,000	0.1642	0.1221	0.4969
16	**Subtotal**			**0.3041**	**0.2261**	**0.9201**
17	**Subtotal w/ Uncollectible Expense**			**0.8601**	**0.7821**	**1.4761**
	Capital					
18	Printer	391	$ 51,088	0.0065		
19	Inserters	391	$ 22,042	0.0028		
20	Building	391	$ 46,202	0.0059		
21	Depreciation Expense (on capital utilized)	403 - Genl	$ 16,483	0.0021		
22	**Total - Capital Cost**			**0.0174**	**0.0174**	**0.0174**
23	**Total - Billing Cost**			**0.8775**	**0.7995**	**1.4935**
	Costs Incurred by IP to Provide SBO					
	O&M					
	Labor:					
24	Reconciling payments	903	$ 40,539	(0.0052)		
25	EDI Contact Person	903	$ 36,844	(0.0047)		
	Capital:					
26	Information Systems enhancement to provide SBO	391	$ 6,949	(0.0009)		
	Other:					
27	EDI Transmittal Cost	903		(0.3500)		
28	**Total - New Costs Incurred**			**(0.3608)**	**(0.3608)**	**(0.3608)**
29	**SBO Credit with RES responsibility for Uncollectibles (line 23 plus line 28)**			**0.5167**	**0.4387**	**1.1327**
30	**SBO Credit with IP maintaining responsibility for Uncollectibles (line 29 less line 16)**			**0.2126**	**0.2126**	**0.2126**
31	**SBO Credit/(Charge)-Combination Customers with RES responsibility for uncollectibles (line 16)**			**0.3041**	**0.2261**	**0.9201**

(1) Based on the methodology specified in the Order in Dockets No. 99-0129 & 99-0134 (Cons.)

Illinois Power Company
Metering Services Rate Base
Twelve Months Ended December 31, 2000
(Thousands of Dollars)

Line No.	Rate Base Component (1)	Balance (2)
1	Plant	
2	Distribution Plant	$ 33,316
3	General Plant	36,992
4	Intangible Plant	12,768
5	Reserve for accumulated depreciation - Distribution	(17,659)
6	Reserve for accumulated depreciation - General Plant	(7,398)
7	Reserve for accumulated depreciation - Intangible Plant	(9,101)
8	Net utility plant in service	$ 48,918
9	Adjustments	
10	Working Capital (Inventory)	480
11	Accumulated deferred income taxes	(8,443)
12	Construction work in progress included in rate base	285
13	Total Adjustments	$ (7,678)
14	Total Rate Base	$ 41,240

Illinois Power Company
Metering Services Operating Expenses (Excluding Income Taxes)
Twelve Months Ended December 31, 2000
(Thousands of Dollars)

Line No.	Account Title (1)	Balance (2)
1	Operating and Maintenance	$ 4,743
2	Customer Accounts	5,268
3	Administrative and General Expenses	8,476
4	Depreciation - Distribution Plant	833
5	Depreciation - General Plant	973
6	Amortization - Intangible Plant	1,283
7	Taxes Other Than Income Taxes (1)	799
8	Total Operating Expenses Before Income Taxes	$ 22,374

(1) Payroll and Real Estate Taxes

Illinois Power Company
Revenue Requirement for Meters Subject to Unbundling
Twelve Months Ended December 31, 2000
(Thousands of Dollars)

Line No.		Metering
1	Rate Base	$ 41,240 *
2	Times Weighted Cost of Capital Before Tax	9.22% **
3	Return on Rate Base	3,801
4	Income Tax Savings Due to Interest Synchronization (1)	(720)
5	After Tax Rate Base Return Requirement	3,081
6	Gross Up for Income Tax Factor (2)	1.65747
7	Return on Rate Base Grossed Up for Income Taxes	5,107
8	Operating Expenses Other Than Income Taxes (3) (4)	22,374
9	Revenue Requirement	$ 27,481

(1) From page 2.
(2) One divided by one minus the effective tax rate.
(3) Total income tax equals line 7 less line 3 $1,306,000
(4) Total operating expenses and income taxes equals line 8 plus total income taxes in footnote 4. $23,680,000

* IP Exhibit 8.8, Page 1 of 4
** IP Exhibit 3.2

Illinois Power Company
Metering Services
Interest Synchronization
Twelve Months Ended December 31, 2000
(Thousands of Dollars)

Line No.	Description	Tax Rate	Amount	
	(1)	(2)	(3)	
1	Original Cost Rate Base		$ 41,240	*
2	Weighted Cost of Debt		4.40%	
3	Synchronized Interest		$ 1,815	
4	Federal Income Tax Savings	32.487%	590	
5	State Income Tax Savings	7.18%	130	
6	Income Tax Savings Due to Interest Synchronization		$ 720	

Type of Debt	Weighted Cost
Transition Funding Instruments	1.26%
Short-term Debt	0.25%
Long-term Debt	2.62%
Preferred Stock (tax advantaged)	0.27%
	4.40%

* IP Exhibit 8.8, page 1 of 4